

Distributed Power Integration Needs Assessment and Testing

A Distributed Utility Integration Test (DUIT) White Paper

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1. Introduction and Overall Project Description

Project Rationale

This White Paper describes and defines a proposed major test of the electrical implications of deep and diverse penetration of distributed energy resources (DER) into distribution systems. As distributed power becomes more commonplace its electrical interactions will become more important to understand and more challenging to manage. This testing program attempts to anticipate such circumstances and discover the problems and benefits that will result from the extensive use of distributed energy resources.

Typically, not enough is known about how distributed resources might perform with regard to safety, health, economics, availability and reliability, especially over time. knowledge is also limited when it comes to interconnection or interface of distributed resources with a distribution grid or customer facility. Operation must be interactive if highest-value benefits are to be obtained, and safety and reliability problems are to be avoided. Energy market players, such as utilities and customers, are traditionally risk-adverse, and will defer decisions to install distributed resources until performance is better known.

Without accurate and demonstrated performance knowledge, early adopters are more likely to encounter failures that will further discourage risk-adverse would-be adopters. Policy makers such as law makers, regulators and public-good funds managers, need test information to help develop, implement and enforce policy decisions that result in improved laws, regulations, codes and standards, and/or technologies.

Even now as the IEEE P1547 committee struggles to propose comprehensive interconnection standards for distributed power, the issue of the allowable penetration level on a feeder is controversial and diverse opinions (but little data) is available to help resolve the issues. DER penetration levels may not even be as important as the types and numbers of technologies in a given locality.

Once the IEEE has approved a set of interconnection standards, individual states and utilities will need to evaluate whether it should be adopted in whole or in part. And utilities themselves might still be circumspect about the applicability of these standards to their typical distribution conditions. Thus an early integration test tailored to address state and utilities' concerns will lead to a more uniform national set of standards by reducing the difficulty in embracing the IEEE standards. This will help make policy more uniform at state and utility levels.

To resolve, or at least shed light on these interconnection issues, the US Department of Energy has asked Distributed Utility Associates and its Distributed Utility Integration Test (DUIT) team members to define and propose a significant testing plan for their consideration. This white paper defines the apparent technical needs for such a test, its objectives and success criteria, siting and technology options, and the cost and timing for

such testing.

The distributed energy resource markets appear ready to expand dramatically due to the emergence of new technologies, uncertain central power supply and delivery costs, and a need for more reliable and high power quality service to critical customers.

As this industry expands and our power system becomes more dependent on distributed power, the efficiency, grid and facility compatibility and reliability of distributed energy resources, and up-to-date and appropriate rules and regulations, become more pressing public issues.

Section 6 of this white paper discusses anticipated results from DUIT testing. While it is impossible to accurately anticipate the eventual results of such a comprehensive and complicated set of tests in advance, it is nonetheless useful to suggest possible outcomes. The following is a set of potential results;

- The concepts of “Electrical proximity factor” and “DER diversity quotient” are new parameters that will be developed and are key to understanding the results of DUIT and hence the integration issues in a broader context.
- The use of sophisticated control systems allows for the capture of maximum benefits that accrue to not only the end user but to the distribution utility, the control system is also capable of capturing the ancillary benefits which have been touted by DER proponents.
- Network systems have a different set of interconnection issues than radial systems, however, the DUIT testing expects to show that many of the protection and interconnect issues can in fact be dealt with in a similar manner. Of course there will be a set of issues that remains unique to network systems and will have to be addressed separately, but the breadth of these issues can be reduced.
- DER operates reliably enough to warrant consideration as an alternative to distribution system upgrades. Generation, transmission and distribution benefits appear to be substantial. Ancillary benefits are possible with the use of a sophisticated control system but quantifying and especially metering them is still problematic.
- A subset of the results from DUIT are scalable to other problems, but there remains a subset which requires computer modeling for accurate prediction and future use. DUIT is useful in both sets of problems. In the class of non-scalable problems, DUIT testing and modeling groups will identify “validation tests” early in the project. The results of these tests will be compared against modeling results for accuracy

History and Status of DER

The Distributed Utility concept involves the use of modular electric technologies that provide electric capacity and/or energy when and where needed within an electricity distribution system. Such technologies, collectively referred to as distributed energy

resources (DERs), or distributed resources, include both distributed generation (DG) and distributed storage (DS). DER may either be interconnected with a large grid or isolated from the grid, but its locational value is high enough that its distributed value is important to its economics and operation. Modular electric technologies (e.g., photovoltaics, fuel cells, microturbines, cogeneration or small battery storage systems) are common sources of DER and have historically been sized to maximize local advantages, usually from the customer perspective. This has led to matching DER to the local loads and dispatching for substantial customer benefits. Dispatch and control by the utility, for the utility's benefit has, for the most part, not been a major consideration in design of these systems.

Utilities can use modular electric technologies to delay, reduce, or eliminate the need for additional generation, transmission, and distribution infrastructure and to avoid some expenses, while firming up voltage and local reliability. If the DER can serve load effectively, the utility avoids incurring costs associated with elements of its traditional "central generation and wires" solution.

Customers can use the Distributed Utility concept in two ways: either to manage their bills and reliability by augmenting their service with distributed resources, or to provide power completely independent of the grid (either by choice or out of necessity). If the customer system is grid-connected, interconnection procedures and contractual relationships with the utility need to be addressed.

While the Distributed Utility concept makes economic sense for the vertically integrated utility of the present, how will the envisioned electric utility industry restructuring affect opportunities for distributed generation or storage and targeted demand management? The potential benefits of using DERs could include reduced capital expenditures for generation, transmission and distribution equipment; increased lifetime of components; reduced line losses; improved reliability and power quality; and expanded customer services. Development of an accepted methodology for evaluating these benefits is only beginning, although considerable work has been done in this area over the last ten years.

The benefits of applying the Distributed Utility concept, whatever they are in a given instance, can be internalized by vertically integrated utilities as part of their regulated business practices. The utility's generation, transmission and distribution planners and operators can determine just the right place and year to install distributed resources to maximum advantage.

DER is in its infancy as a utility solution for cost reduction, improved utilization of T&D resources, and enhanced system reliability (e.g., ancillary services such as operating reserves and voltage support). Nevertheless, end-use customers have been using on-site power in various forms for many years to achieve a variety of benefits, including: improved reliability (standby/emergency power), reduced demand charges (peak shaving, interruptible rates, power factor improvement), reduced energy costs (cogeneration, prime power in areas with high electric rates or no electric service); etc. Traditional technologies such as reciprocating engines and steam or gas turbines have an outstanding track record of providing end-use customers with these and other benefits. Emerging

technologies such as microturbines, fuel cells, photovoltaics, and energy storage systems hold promise to provide customers with these same benefits and other desirable enhancements (e.g., improved power quality and uninterruptible supply) at higher efficiencies and reduced emissions.

What is missing from the customer side of the equation is proof that traditional and emerging technologies can all work together seamlessly to provide the desired “mixture” of benefits from the use of a combination of various technologies. What is missing from the utility side of the equation is proof that any of these technologies can be used as reliable DER resources to improve system operation and lower the cost of electric service for all customers. Questions that need to be answered before either utilities or customers will widely adopt DER as a means of achieving the benefits include:

- Will there be significant systems integration and interoperability problems when installing and using different kinds of equipment from different manufacturers (e.g., conflicting modes of operation, inability to “load share” between multiple units, inability to communicate with units for maintenance and tracking purposes, etc.)?
- Can “islanded” operation as a “microgrid” be automated to best utilize the features and characteristics of different DER technologies to serve base load, intermediate load, and peak load requirements at a facility?
- How will multiple DER technologies at a facility interact with the grid when interconnected and can these resources be managed safely and cost-effectively along with other utility resources?
- Can DER resources be integrated cost-effectively into other utility systems such as substation automation, distribution automation, and customer billing systems?
- What benefits, if any, do DER resources provide with regard to voltage regulation, power factor improvement or other ancillary services?
- Do we need “DER Standards” for issues such as metering and billing, protective relays for safe interconnection with the grid, emissions and other permitting requirements, communication protocols for proper fault recovery and system coordination and management, etc.?
- Will there be adverse interactions between different types and brands of DER technologies that could actually create power quality problems rather than alleviate them (e.g., harmonics from inverters)?
- What economic and reliability benefits can the utility really expect to achieve from having automated dispatch capabilities?
- Can DER resources participate cost-effectively in ISO/PX bidding procedures for either generation supply or customer load on an aggregated basis?
- Is there a DER technology demonstration project available anywhere in the public domain to help utilities, manufacturers, and customers make informed decisions

with regard to the claims surrounding the DER?

We expect to perform one or more Integration Tests at or near utility substations which allow the generation and storage components to work together, as facilitated by a flexible yet powerful control and information infrastructure. These tests will be designed to address the above questions.

2. Scope, Objectives and Goals

Project Scope

The Distributed Utility Integration Test (DUIT) project would result in the first full-scale integration test of distributed generation and storage technologies in the United States. The DUIT will have a broad test plan that will include a detailed exercising of variously configured systems with sophisticated monitoring to document the interaction of the various components both within the system and with the electric utility grid. DUIT's test plan is intended to focus on DER integration and aggregation issues, not on DER technology itself. Grid interaction problems and benefits will both be evaluated.

The DUIT project will seek to establish one or more integration test sites at or near utility substations that will allow small generation, storage and distribution control components to operate under the management of a communication and control system. Multiple test sites may be required to minimize the cost to simulate a broad enough variety of distribution and technology circumstances to meet national needs.

A key aspect of the DUIT project is a thorough test of the feasibility and value of co-location and integration of diverse distributed generation and storage technologies into the electric distribution system. Ideally several distributed generation and storage technologies would be installed within electrical interaction proximity of each other to allow for their aggregate benefits and operational issues to become evident.

This local collection of distributed generation and storage technologies will be managed by a state of the art control system, demonstrating feasibility of remote operation, monitoring and dispatch.

The units will be instrumented to measure the potential electric distribution system advantages and challenges of substantial penetration (significantly greater than 10% of local load) of distributed generation and storage at distribution voltage levels. The data will be gathered and analyzed to characterize the actual value of distributed generation and storage to ratepayers and utilities (e.g., avoided costs, distribution cost savings, lower energy cost).

Project Objectives

The primary objective of the DUIT Project is to advance the state of the art in distributed generation and storage integration practices and strategies in order to accelerate the market entry of advantageous modular technologies, leading to lower ratepayer cost of service and improved service quality and reliability.

The goals of this project are: to prove the feasibility and quantify the benefits of the integration of diverse distributed generation and storage technologies in a distribution system; and to provide a testing ground for observing and measuring the beneficial and/or detrimental interactions between the distributed technologies on the distribution system. Achieving these goals requires a project that will entail full-scale multi-megawatt implementation, testing and demonstration of distributed generation technologies in an actual utility installation.

From the customer stakeholder's perspective, proof is needed that traditional and emerging technologies can all work together seamlessly to provide the desired mixture of benefits (to several stakeholders) from the use of a combination of the various technologies.

Utilities are seeking evidence that any of these technologies can be used as reliable DER resources to improve system operation and lower the cost of electric service for all customers.

Technology development stockholders have a significant interest in DUIT as it provides a vehicle for demonstrating the benefits of their equipment to customers, utilities and regulators. Confidence by these bodies removes significant barriers to the wide scale adoption and implementation of DER technologies. Large scale adoption also creates the opportunity for new business initiatives such as the development of privately held, independent distributed resource generation and storage projects.

From a policy standpoint, federal, state, and utility regulators will be more confident as they consider standardization of interconnection procedures.

The increasing potential of distributed resources in emerging utility markets has focused attention on two critical issues: interconnection of distributed resources with the electric distribution system, and the unknown nature of potential interactions between multiple distributed devices. Interconnection is a critical issue because of the diversity of distributed technologies and the variability of interconnection standards and practices from state to state and utility to utility. Interactions between multiple DERs are largely unpredictable due to limited operating experience to date; this uncertainty contributes to the inhibition of market acceptance of DER.

By examining current and emerging technologies and operational concepts to properly integrate diverse distributed resources, this project will provide new insights into grid support issues and will ultimately suggest innovative system protection design concepts.

In particular the DUIT test will illuminate the following DOE issues:

- Universal distributed and electric power system interconnection technology including current and advanced/future designs; requirements and tests for interconnection.
- Interconnection equipment performance and functional characterization and installation test method design, development, validation and documentation.
- Command, control, communication, monitoring, and remote and on site intelligent controls for interconnection.
- Interconnection equipment/technology tests and procedures.
- Design and development requirements for the establishment of an industry wide third party for interconnection equipment as well as for on-site interconnection approval.

Technology and Distribution System Selection

The test site could be configured, and equipment installed and instrumented as early as 2001 with off the shelf distributed generation and storage components. Ideally, a range of modular generation and storage technologies will be investigated. The possible portfolio of distributed generation technologies could include natural gas or dual-fueled engines, small gas turbines, microturbines, photovoltaics, and fuel cells. Energy storage DERs could incorporate energy storage technologies such as state-of-the-art and advanced electrochemical battery systems, flywheels or superconducting magnetic energy storage (SMES).

Selection of specific DER units will be based on several rank-ordered criteria: DER technology diversity, diversity of electrical generation hardware (i.e., rotating and DC output), preferred “clean” technologies (minimal emissions and permitting requirements), DER electrical rating, total electrical rating of all DERs, consistency with host utility needs/objectives, cost (purchase lease/rental), installation, fuel supply, fuel system(s), commercial availability, and “transportability.”

A review of distribution system types across the country will guide the selection of the DUIT distribution system configuration(s) (radial, network, etc.) so that the test results will have the largest possible direct impact. Where different configurations exist, the data collected at DUIT will provide technical guidance and modeling validity to integrated DER performance on those dissimilar configurations.

Controls

The DUIT collection of local DERs will be managed by a state-of-the-art communication and control system. The system aggregates DERs and presents them to the system operator as one resource. Available capacity, capacity that is scheduled or committed, and current aggregate output is presented to the operator through the systems graphical

interface. Available capacity may be scheduled by start date, time and duration, or requested at once. Resources may be grouped by defined characteristics (e.g., location, emissions, heat rate, etc.) and groups of DERs may be scheduled or dispatched individually.

Tests will provide important indications of needs related to monitoring, controlling, and beneficial dispatch of DERs. DERs and the power distribution system to which they are connected will be instrumented to measure a range of parameters that provide meaningful indications of the potential advantages and Drawbacks associated with substantial DER penetration at distribution voltage levels.

Documentation

The detailed documentation of the integration testing will be made available to those considering the development or installation of a distributed generation system. With the communication of the results of the DUIT to electric utilities, customers, developers and equipment suppliers, fewer barriers will be placed in the way of intelligently designed distributed generation components and installations.

Federal Role

There is a “natural” federal role in the sponsoring and administration of the DUIT testing that results from;

- regulatory changes in the vertical utilities of the past,
- the new role of customer stakeholders as energy providers and selectors,
- the proliferation of new and diverse technologies and technology companies that have emerged over the past five to ten years.

Federally sponsored DUIT testing will provide objective, real-world test conditions for DER, which because of its complexity and broad set of stakeholders would not likely be performed by any of the individual stakeholders. The sponsoring by federal agencies will ensure widespread and uniform dissemination of test results and documentation that could not be guaranteed with other sponsoring bodies. This is critically important, as state and local regulatory agencies move to adopt national standards such as IEEE 1547 or generate their own standards. The more uniformity that is built into these standards, the higher the likelihood that all of the purported benefits of DER can be realized.

Historically, the vertically integrated utility selected the technologies that made the most economic sense to install from their perspective. Testing was largely performed by the utility and the technology manufacturers. When the utility had complete control over the technology selection and there was no technology “stretch” involved, the utility could be confident of its own decisions and its own protection coordination practices. The advent

of DER now places much of this selection and operation responsibility on the energy end-users, most of whom have no test capability prior to installation or during operation. The end-user is also usually limited in his concern for issues such as grid interactions as his objectives typically tend to be focused on cost containment and backup power availability.

One could argue that the role of testing in this new DER environment would then fall to the DER manufacturer, but sole reliability on this stakeholder also has its drawbacks. Most testing performed by manufacturers is done under highly controlled conditions with the intention of developing a data specification sheet for potential customers. At times this information can be incomplete, and equitable comparisons to other technologies can be difficult. If performed in an accredited laboratory, testing of a manufacturer's production units will logically result in certification testing, in which the parameters of a particular make and model are credibly established and warranted by the manufacturer. The result is that a utility (or other end user) need not require testing of every such unit that is proposed for interconnection. While this is important testing, it can be self-serving and focused on technology with less interest on utility or grid integration issues.

This is why multi-stakeholder integration testing such as DUIT is being proposed and why it is unlikely that such testing would take place in the absence of federal sponsorship. DUIT will be a technology-utility- neutral test facility with a strong team of organizations and individuals who have been active in DER concept and integration development over many years. This unique test facility is necessary to fully realize the diverse economic and environmental benefits of DER.

3. Technology Selection and Evaluation

Technology Selection

The purchase of distributed generation and storage hardware is beyond the budget and scope of this project. Commercial or near-commercial DERs will be rented, leased, or borrowed. Ownership of equipment is not necessary to meet the project's goals and objectives. Therefore rented or leased equipment will minimize system engineering, and procurement costs and lead times.

Several DER suppliers have already been approached by team members about the possible loan of equipment for such an integration test. Some DER technology developers may be eager to include their systems in a world-class, groundbreaking project like DUIT.

The project is meant to measure and analyze the interactions between units rather than prove the operation of any single distributed generation technology and storage component; thus rental, lease or loan of "off-the-shelf" distributed generation and storage units is preferable from both test design and budgetary standpoints.

The team will make final selection of which distributed generation and storage technologies to include based on the following criteria, which will be prioritized by the project team:

- Diversity of technologies (more than one type of distributed generation and storage variety is mandatory, preferably three or more).
- Diversity of electrical generation hardware (both rotating and power electronic conversion types are highly desirable).
- Pre-existing on-site distributed generation and storage technologies.
- Clean technologies with minimal emissions or permitting problems.
- Individual DER unit electrical rating size (10 kW to 2 MW would be ideal).
- Total electrical rating size (1 MW to 3 MW would be ideal).
- Host utility objectives such as compatibility with site physical limitations.
- budgetary considerations such as lease costs, installation costs or fuel supply hardware.
- Use of proven, off-the-shelf (i.e., reliable, tested, trouble-free) distributed generation and storage technologies in order to separate integration factors from new technology issues during operation and testing.
- Technologies whose development was supported by one of the project participants.
- Since many of the DU technologies are relocatable (e.g. batteries, small gensets, flywheels) the project may be able to allow some units to be in place for only relatively short duration tests, perhaps lasting a month or more.

Some of these criteria may conflict with one another, making the technology and site selection efforts critically important to the success of the project.

Technology Evaluation

Each of the prospective technologies will be evaluated upon the criteria presented below

Physical – characteristics

- size, weight, venting, fuel requirements
- indoor/outdoor requirements
- enclosure temp. control etc.

Electrical

- rated parameters
- fault duty
- short circuit current capacity
- max current inrush
- included protective devices

Mechanical

- mounting & other mechanical requirements
- manual shut-off

Environmental and permitting

- Emissions
- air
- water
- other permitting needs?

How long can we use?

- Cost, rent, lease, buy ? special discounts?
- Availability
- O& M requirement
- Certified to what standards?

Applications of DER

Distributed generation systems may be composed of one or more primary technologies such as internal combustion engines, combustion turbines, photovoltaics, and batteries. Innumerable combinations of DER technology/fuel options are possible, to take advantage of synergies between individual technologies, making them as robust and/or cost-effective as possible

Most DER systems operate on gaseous or liquid hydrocarbon fuel to produce electricity as needed; natural gas fuel is piped in, while diesel fuel is stored on-site. Battery systems store electric energy from the grid for use when needed. Renewable energy DERs use solar or wind energy as fuel.

One important DER type category is the duty cycle for the DER for “peaking” duty cycle applications DERs only operate for a small portion of the year, usually between 50 – 600 hours annually, and for “baseload” duty cycle DERs operate for many hours per year for.

Peaking duty distributed generation tends to have relatively low installed cost and can take on load in just a few minutes (or less). It tends to be relatively inefficient and have significant air emissions per hour operated. Peak duty cycle DERs usually operate for just a few hundred hours between overhauls. Typical installed costs range from about \$200 – \$500/kW and non-fuel operating cost ranges from 1¢ - 5¢/kWh.

Primary distributed generation technologies used for baseload duty cycle (compared to peaking duty cycle described above) tend to be fuel efficient, reliable, and cleaner burning combustion-based options. Typical installed costs range from about \$400 – \$800/kW and non-fuel operating cost ranges from ½¢ - 3¢/kWh.

Most types of distributed generation can provide useful and valuable thermal energy. To do so, additional equipment (e.g., pipes and pumps) is added to the generation system so that during electricity generation otherwise wasted heat energy is captured and used to heat water or air, or for industrial processes. This concept is often referred to as combined heat and power (CHP) or cogeneration. Depending on type of generator used, existing thermal energy infrastructure in the facility, and many other project-specific factors, equipment for CHP can add 25% - 100% to the installed cost for a generation-only system.

Important “enabling” subsystems include:

- power conditioning equipment such as electricity generator, transformer, and inverters
- controls
- communications
- fuel handling and/or fuel storage
- emission controls
- sound attenuation enclosures.

Appendix 2 provides a summary of DER technologies.

4. Site Evaluation and Selection

Site Assessment Criteria

Background

The goal of DUIT is to perform testing to determine how distributed generation and storage technologies might interact with the electric grid, with each other, and with adjacent customers and loads on the distribution feeder. In particular, DUIT testing is designed to illuminate certain other specific issues with regard to penetration of distributed resources into the electric distribution system. These would include interconnection technologies and practices; interconnection equipment performance and functional characterization; instrumentation, monitoring and control technologies; and methods of controlling distributed generation remotely, whether in a utility/regional hierarchical scheme or in a local/independent mode.

It is envisioned that multiple distributed generators, storage devices, load banks, capacitors and other components would be installed at the test site and operated in a variety of configurations, by means of state of the art control, communications and data-logging systems. Monitoring and data recording of key parameters would be carried out in order to evaluate the performance of DERs and determine potential problems or issues that may arise. This knowledge is then used to draw conclusions about how the DERs may perform in “real world” distribution systems.

DUIT will require a laboratory test site (or combination of sites) that is capable of accommodating the installation and simultaneous operation of multiple DERs along with monitoring and instrumentation systems, data logging hardware, and the requisite support facilities, such as fuel supply and storage. A survey has been conducted of known laboratory facilities, particularly those that have conducted research and testing on distributed resources. Leading DUIT sites as of this writing include:

- The Modular Generation Test Facility (MGTF) in San Ramon, CA, owned by Pacific Gas & Electric Co. (PG&E)
- The Nevada Test Site (NTS), operated by the US Department of Energy (DOE)
- UC-Irvine Laboratory, Irvine, CA
- American Electric Power (AEP) Dolan Test Center, Groveport, Ohio

Assessment Criteria

Given the foregoing rationale, the criteria in the following list were developed and used in the assessment of each site.

- Available space – number of test cells or bays, their sizes, and limitations
- MW Rating – largest single DER allowable; total allowed DER for facility
- Existing/permanent DERs on-site
- Existing equipment – control, monitoring and instrumentation; switching; load banks
- Ability to test in both radial and network circuit configurations
- Grid supply – voltage, MVA, switching arrangements, and limitations
- Fuel supply and storage – natural gas line size, pressure (psi) and flow rate (BTU/hr); diesel, hydrogen, gasoline, LPG availability and/or storage capability
- Limitations – noise, emissions, other
- Ability to test multiple DERs at once, in interactive modes
- Number and expertise of testing staff
- Testing history/experience relevant to DUIT

PG&E has been a member of the DUIT team since the submission of the original proposal to NREL in January of 2000. The preliminary cost estimates for modifying sites for DUIT testing has been based on the PG&E Modular Generation Test Facility (MGTF) in San Ramon, which the utility has offered as a candidate.

5. Electrical and Operational Issues

Why Distribution and not Transmission?

Generators that connect at transmission level are usually much larger than DER (>50

MW) and are designed to export power to the utility grid. For this type of situation, existing utility tariffs and interconnection procedures are known and are well defined, providing precise information to a generator developer. In addition, utility planning engineers will perform the requisite impact studies by modeling the addition of the generator to the grid and running power flow and stability programs to verify that the generator will not negatively impact the system. These practices are well known to all participants in the process.

DER is by definition generation that is to be connected to the distribution system. Most utility distribution systems were not designed with generation in mind: the basic idea has historically been to take power from the transmission system and distribute it to customers. The majority of distribution in the US is radial, not networked, and the impacts of generation can be more pronounced on a networked system. Given that the penetration level of DER in the distribution system to date has been small, more needs to be known about impacts to the system, and to other customers, especially the potential for interactions between DERs on the same feeder.

Extensibility of DUIT Results

In the selection of the DER resource and distribution system configuration(s) for DUIT, every effort will be made to maximize the value of the results by testing what is determined to be the most likely system configuration(s). It is not possible, however, to test every possible combination of DER and distribution system configuration. The question then arises, is it possible to extend the results from DUIT to these dissimilar configurations? The short, but not simple answer to this question is that a subset of classical problems and analysis is relatively straightforward to extend, while another subset of problems is much more difficult to extend. DUIT has an important roles in dealing with both of these situations.

First, the subset of classical problems which are scalable need to be defined and classified from those which do not, DUIT testing will aid in this classification process. Secondly, protection and load flow problems which do not scale effectively out of DUIT testing can certainly be addressed by computer modeling. Here the importance of DUIT is that a significant number of these problems will be identified for DUIT testing and modeling early in the project. Validation of the models for these types of problems will be performed. To obtain maximum benefit from these models, there will be close coordination and planning of such validation tests between modeling and testing teams.

Identification of Test issues

A non-exhaustive list of the electrical and operational issues which are to be considered for DUIT testing are shown below. These items will be screened by DUIT team

members, as well as by external reviewers to prioritize the list. The emphasis of DUIT testing is on integration issues and items which fit into this category will naturally receive high priority.

- Design and Manufacturing (UL 1741)
 - Surge Withstand Capability
 - Immunity Protection
 - Field-Adjustable Trip Points
 - DC Isolation
 - Dielectric Voltage Withstand Test
 - Power Factor
 - Harmonic Distortion
 - DC Injection
 - Utility Voltage and Frequency Variation
 - Reset Delay
 - Loss of Control
 - Short Circuit Contribution
 - Load Transfer Synchronization
- Installation and Commissioning
 - Metering and Instrumentation
 - Grounding
 - Pre-parallel Inspection
 - Protective Function
 - Verification of Final Protective Settings
 - Trip Testing
 - In-service
 - Flicker
- Grid Impacts
 - Load Following
 - Parallel-standalone Transition
 - Power Quality
 - Harmonics
 - Power Factor
 - Flicker
 - DC Injection
 - EMI/EMF
- System Protection
 - Abnormal Conditions: voltage/frequency trip points, reverse-power/under-power trip points, fault detection, loss of synchronism
 - Islanding
 - Synchronization
- Distribution System Impact/Interaction

- Network Systems
 - Fuse Protection
 - Recloser Coordination
 - Short Circuit Current Contribution
 - Capacitor Switching
 - Stability
 - Cold-load Pickup
 - Sectionalizer Operation
 - Voltage Regulation
 - Substation Backfeed
 - Single-Phase Faults
 - Faults on Adjacent Feeders
- DER to DER Interaction
 - Islanding
 - Centralized Control

6. DUIT's Potential Results and Policy Implications

Electrical Results

The two factors that ultimately help determine the widespread acceptance of DER are overcoming existing electrical concerns regarding large-scale DER operation on distribution systems and confirmation that the identified benefits of such generation can in fact, be realized in real world settings. Broadly, the results obtained from DUIT testing will be targeted at answering these two questions.

Installation and operation of DUIT will be focused on testing the integration and interaction of multiple, diverse DER with one another, as well as their interactions with the distribution system. This testing will provide a thorough “real world” attempt to confirm the applicability, usability, and limitations of the new IEEE P1547 standard and other interconnection rules.

Additionally, it is expected that unforeseen obstacles will arise from the installation and operation of DER at DUIT. These events are viewed as a benefit of doing the testing and, if possible, solutions to these problems are expected to be developed, documented, and implemented quickly in the DUIT test environment.

Section 5 of this paper presents a partial list of test issues. As mentioned, these issues will be prioritized and modified to fully investigate the interaction of the DER with the grid. It is expected that DUIT testing will confirm and identify necessary modifications and potential enhancements to existing standards and in this process, the results and documentation should be persuasive in overcoming existing concerns of utilities and regulatory bodies.

While it is impossible to accurately anticipate the eventual results of such a comprehensive and complicated set of tests in advance, it is nonetheless useful to state the questions upon which DUIT will be working towards answers.

- Will diverse DER units be shown to be electrically compatible with one another?
- Which DERs are capable of load following and which are better suited to baseload?
- The stiffness ratio and short circuit current contribution can be effectively applied to those issues identified by 1547 by using a variable distribution length feeder of 10, 20, and 30 miles?
- Do diverse DER's permit adequate grounding?
- The concept of "Electrical proximity factor" and "DER diversity quotient" are new parameters that are key to understanding the results of DUIT and hence the integration issues in a broader context.
- Will IEEE P1547 provide adequate interconnection guidance, or will, much more sophisticated standards appear to be needed as DER penetration of UL-1741-compliant inverter-based technologies exceed a certain level?
- Too fully realize the value of DER, both from an end-user point of view, as well a distribution company perspective, the need for sophisticated control systems is required? This control system also is required to maximize ancillary benefits.
- Network systems are different from radial systems. However, DUIT testing confirmed that many of the protection issues are the same, and while there still remain some unique issues to radial systems, the difference is less than originally thought?
- Network protectors reacted identically to DER as it did to existing regenerative loads?
- DER operates reliably enough to warrant consideration as an alternative to distribution system upgrades? Generation, transmission and distribution benefits appear to be substantial; ancillary benefits are possible but quantifying and especially metering them is still problematic. Dispatching the ancillary benefits is possible by use of the DER control system.
- The use of computer modeling and a set of validation tests at DUIT, together with the set of scalable DUIT results, allows accurate prediction of a large set of future DER installation issues?

End User and Utility Potential Benefits

The realization of conceived benefits is another important and expected result from DUIT testing. The economic benefits of location, dispatchability, ancillary benefits and others will be validated through demonstration at DUIT. A complete list of potential benefits, both utility side and customer side, is presented in Appendix 3.

Policy Implications

The list of potential results above illustrates the types of issues which will be resolved, raised, or illuminated by the DUIT. The impact of having these technical answers in

hand will differ depending on the stakeholder considering important distributed generation decisions:

- Regulators will be able to make more informed decisions regarding adopting IEEE P1547 or other proposed interconnection standards.
- Deeper distributed resources penetration of the distribution will be much better understood and accepted by utilities..
- Utilities will be able to see firsthand the protection afforded by those standards and better understand the remaining issues.
- Utilities/distribution companies will have more substantial proof and confidence in the use of distributed resources for their own purposes.
- ISOs, RTOs, GENCOs, TRANSCOs, and energy brokers will have more confidence in the operation and benefits of grid connected distributed generation.
- Distributed generation installations will be less likely to be required to have excessive costs due to interconnection fears.
- Customers will have more surety that their distributed resources will be interconnected safely, smoothly, and with minimum cost.
- Customers will be less likely to be adversely impacted by their neighbor's distributed resources.
- Manufacturers will be able to better anticipate the types of protection devices required for most beneficial incorporation of distributed generation into utility systems and/or at customer sites.
- Standards setting bodies such as IEEE will feel more (or less) comfortable about aspects of the current standards, leading them to refine, reconsider or expand subsequent versions.
- Some stakeholders will consider the DUIT as a good first step but still inadequate to resolve some of their most important issues.

7 Statement of Work, Costs, and Schedule

Statement of Work for Distributed Utility Integration Test

Task 1 Develop and Implement Procurement Process

Develop and implement a procurement process for vendors of the distributed generation units that will be tested. A framework for evaluating the proposals will be developed with key stakeholders' input. This will be used to undertake a systematic review of proposals/quotes that are submitted.

Develop a procurement package for RFP for all DERs and infrastructure components not already on site, except control system and DAS. These will include the above specifications, terms and conditions, and delivery schedules for the hardware.

Task 2 Develop Control System Specifications

Develop a state-of-the-art control system specified for DUIT technologies. It will be designed to provide important validation of the concept of monitoring, controlling, and optimal dispatch and reflect, to the extent possible, monitoring and control needs for “real-world” projects. Other issues that will be addressed are:

- how data can/should be processed
- how much data can/should be used to communicate and control
- which/how much data operators need
- what control variables are most important. Controls should also allow for evaluation of benefits and issues related to islanding.

This task is expected to result in a control system specification that will be used to manage the DUIT while it is being tested.

Task 3 Develop Project Technology – Specific Engineering and Electrical Test Plan

Develop a project test plan that will determine the following data requirements as related to the DER units:

- DER capital and installation costs
- DER operating and maintenance costs as well as operating manpower
- Fuel consumption, fuel cost, and fuel availability
- Operations log, annual capacity factor, annual kWh produced, plant annual kWh consumed
- Unit reliability and reasons for loss of grid power, lost or damaged product value estimates, consumer economic parameters, predicted outages, etc.
- Measured environmental disturbances: emissions, noise, etc.
- Installation or operating issues: interconnection rules and their compliance costs, miscellaneous sitting hassles, applicable environmental regulations, permitting time and cost, problematic safety procedures, etc.
- Cogen heat value, if any

The test plan will determine the following measurements and data requirements as related to the utility’s perspective:

- Ten minute resolution substation loadings, feeder loadings, loadings at customer meter, and transformer loadings
- Ten minute resolution generator supply measurements
- Note substation or feeder problems
- Gas supply constraints or other fuel delivery problems
- System estimates of potentially deferrable distribution investments, maintenance reductions, reinforcements, potential lost customer revenue, accelerated aging
- Utility safety procedures or concerns
- Relay or fusing or other protective concerns
- Projected feeder and substation area load growth

- Customer rate schedule changes and revenue impacts
- Gas supply, feeder and substation load or physical characteristics which would assist in extrapolating the results to other locations
- Subjective utility distribution engineer sentiment at the end of the experiment, list of lessons-learned and suggestions for improvements
- Historical utility problem records or personal recollections
- Acceptance testing process and data
- Generator cycling tests
- Measurements along the feeder and reliability enhancements for other customers
- Load tap changer frequencies, transformer top oil temperatures
- Real time fuel flow or exhaust emissions
- Other staged test specified by the distribution operators as test progress

The test plan will determine the measurements and data requirements as related to the sponsor's perspective which will include all of the utility data and gas supply, feeder and substation load or physical characteristics that would assist in extrapolating the results to other utility locations.

This task is expected to result in a letter report describing the data required to match the analysis results, data acquisition plan, schedule, and etc.

Task 4 Pre-installation Engineering Design Diagrams and Line Diagrams

Under this task, all of the pre-installation engineering will be performed. This includes design and line diagrams for the selected technologies, instrumentation, and monitoring equipment.

A final design review with all stakeholders will be held before installation begins.

Task 5 Install DER and DS Systems and Acceptance Testing of DER and DS Systems

Install all DER and DS systems. Once installed the DERs equipment will undergo acceptance testing to verify that they perform as specified, per selection criteria developed in the Base Year.

This task is expected to result in the installation and acceptance of all DER and DS systems.

Task 6 Develop Data Acquisition System (DAS) Specifications

Develop specifications for the data acquisition system. The DAS will be designed and fabricated to continuously monitor operational parameters of the selected DER systems.

This task is expected to result in a letter report that describes the required data acquisition systems and list the specifications.

Task 7 Install Data Acquisition Systems

Install the DAS in coordination with the installation of the DER and control subsystem.

This task is expected to result in the installation of the DAS.

Task 8 Install Control Systems

Install the control devices for each individual DER, interconnection with the sensors/monitoring used for the DAS, interconnection of the control devices into a “control system”, and testing and tweaking of the control systems’ operation.

This task is expected to result in the installation of the control system.

Task 9 System and Subsystem Shakedown: DER/DS, Control, and DAS

Test the operation of the DERs both separately and running concurrently.

This task is expected to result in a letter announcing release of the system for normal operation and data acquisition, including documentation of any major shakedown problems and their resolution.

Task 10 Acquire Data

Acquire data from the DUIT for a period of six months. This task includes the development of a Microsoft Access database software tool used to store and process data, download data from the DAS, and automatically screen data for consistency and validity. Monthly performance summaries will be prepared and data will be formatted and transmitted to DUA for detailed analysis. This task may also include up to five special tests undertaken to evaluate specific effects from the use of DERs. Typically, these test involve monitoring of operational scenarios and/or causing disturbances on the local grid and recording the response. Special tests may also address topics such as islanding, voltage/load support, harmonics, peak shaving, etc.

This task is expected to result in monthly performance summaries.

Task 11 Analyze Results

Organize and analyze all data and qualitative information with the objective of characterizing important technical impacts and associated with significant penetration of the distribution system and determining the quantitative evidence of economic benefits associated with use of DERs.

This task is expected to result in analysis summary report including methodology and assumptions.

Schedule

Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Date	8/01	9/01	10/01	11/01	12/01	1/02	2/02	3/02	4/02	5/02	6/02	7/02	8/02	9/02
Task 1	***	***	***	***	***	***								
Task 2	***	***	***	***										
Task 3	***	***	***	***	***	***	***	***	***					
Task 4				***		***								
Task 5							***	***	***					
Task 6				***	***	***	***	***						
Task 7									***	***	***			
Task 8									***	***	***			
Task 9											***	***	***	

Task 10 Data Collection from start up to six month.

Task 11 Analysis up to one year from start.

Cost and Related Deliverables

Deliverable Description	Due	\$Value
Develop and Implement Procurement Package (Task 1)	1/31/02	\$102,000
Develop Control Specifications (Task 2)	11/30/01	\$80,000
Component –Specific Engineering/Electrical Test Plan (Task 3)	4/30/01	\$150,000

Analysis/ Modeling Task – set aside

Pre-installation Engineering Design Diagrams and Line Diagrams (Task 4)	1/02	\$200,000
Install and Test DER (Task 5) 1 – 8 hr a day fuel cost 1.500 kW 25,000-200,00 NG	4/30/02	\$1,400,00
Data Acquisition System (Task 6)	3/30/02	\$120,000
Deliver and Install DAS (Task 7)	6/30/02	\$30,000
Deliver and Install Control System (Task 8)	6/30/02	\$80,000
Monthly Progress Reports	15 th of month	\$5,000/ report
Shakedown Report (Task 9)	8/31/02	\$50,000
Deliver Data Records (Task 10)	1/31/03	\$112,000
Data Analysis and Final Report (Task 11)	4/30/02	\$120,000
	Total	\$2,504,000

8. Appendices

Appendix 1 Q & A

How will this project advances science or technology especially with respect to resolving the key issues?

This project will provide answers to many of the questions listed above that have thus far prevented DER from being used pervasively as a utility solution – despite its attractiveness in “paper studies” that were initiated nearly a decade ago and have proliferated ever since. Customers will be able to refer to an actual “case study” to learn about the interactions between various DER technologies, the systems integration and interoperability issues, and the capabilities of setting up an automated “microgrid” to serve some or all of their own power needs. Manufacturers will have a “proving grounds” to identify possible weak spots in their designs and the need for “standards”, as well as to gain insight into the optimization of their technologies when applied in combination with other technologies. And finally, utilities will have the chance to review “real world” experiences in dispatching DER for peak demand reduction plus enhanced system/customer reliability, while determining what efforts may remain for DER to be integrated with other utility information and management systems.

Why some or all of the project will not be adequately addressed by the competitive or regulated markets?

Regulated utilities are severely cutting R&D to prepare for competition that will result from deregulation. These same utilities are also not willing to experiment with new technologies by using customers as “test sites.” To make matters even worse, regulated markets have no economic incentive to look for more cost-effective solutions if it means incurring any additional risk whatsoever (whether real or perceived). While competitive markets may eventually change this situation, most utilities have not yet figured out whether DER is an opportunity or a threat to their future business. Thus, it is unlikely that this type of DER demonstration project will be undertaken by a regulated utility to serve the public good, and competitive markets would, of course, keep results of this nature proprietary as a means of obtaining a competitive advantage.

The Distributed Utility Integration Test is clear example of the need for state and local level research in the common good. Since it is the interaction between distributed generation and storage technologies which is being investigated the DUIT project helps customers and utilities alike, and is supportive of all distributed generation and storage technologies simultaneously. Thus the benefits of the project are substantial and broad while the likelihood of any individual firm undertaking such a test are very small.

By representing many perspectives and stakeholders, and being an objective intermediary and project supporter the is clearly accelerating the process of seamless integration of distributed generation and storage into the marketplace.

What will determine if the project is successful?

In many ways this project will set the standards by which distributed generation and storage technologies will be measured regarding their applicability for distribution system integration. No one has attempted deep penetration (greater than 10% of the local load) of the distribution system with distributed generation and storage. The team does not know precisely what to expect and what problems may be encountered. Studies of the impacts of distributed generation and storage on the distribution system to date have not predicted concerns, but without testing in the real world this cannot be proven to the point where customers and utilities will feel comfortable with these units in the system.

The project will be a considered a success if;

1. Any electrical problems which occur are captured by the instrumentation for further analysis and resolution
2. The field experience and its subsequent analysis teaches the distributed resources community how to improve its components, integration techniques, economics, maximize its benefits and/or which electrical interconnection situations should be avoid in the future
3. The distributed generation and storage interconnection standards are confirmed or revised as regards safety, reliability, protection, economic impact on project costs, etc.,
4. The electrical and economic results of this test can be extrapolated to similar locations, technologies and circumstances
5. Utilities and customers feel more confident of the benefits and concerns of significant distributed generation and storage installations.

Why this test should be performed now?

Distributed generation and storage technologies are only now being considered for the broad range of applications which they can address. To date their cost, efficiency, emissions and reliability have not been able to compete with many central station technologies. Further, their positive attributes of local benefits have easily been overlooked by utilities used to optimizing very large plant operations and economics.

Recent advances in technology costs and performance, massive planned investments by the modular distributed generation and storage industry, and the delamination of the electric utility industry have changed the rules of the game to make distributed generation and storage a near-term reality.

But one of the hurdles that will remain (even if the technologies themselves are ready) is the lack of field experience and successful integration via a robust distributed generation

and storage controls system. This project is the most timely way to address both of those hurdles.

Who makes up the DUIT team?

Members of this team have been active in distributed resources concept development, integration technology development, and in defining the objectives and design of a test to assure the seamless integration of distributed generation and storage into utility systems.

The scope of the team goes beyond its members, our contacts and influence with other research organizations, technology developers, and utilities will continue to be an important part of this project. This project would be the culmination of nearly a decade of distributed resources research and development by the team members.

It is clear that a more complete evaluation of the benefits and limits of operation of DER for all stakeholders, e.g., energy customers, electric transmission and distribution companies and equipment manufacturers, is needed. Increased general awareness through projects like the DUIT and other documented success stories will highlight where the hypothesis that DER is beneficial has been tested to key decision-makers and assist in increasing market acceptance of the distributed generation concept. The ultimate deliverable of this project is a report documenting all aspects, results, conclusions and recommendations resulting from this project. Ensuring that the knowledge base developed and results of this integration test are transferred to the appropriate targeted audiences, state regulators, electric utilities and energy customers, is critical to address the issues described in the project objectives and to reduce any institutional or operational barriers that may be preventing the DER market from being fully realized. In addition to the periodic, topical and final reports that are documented in this proposal, the project team will interact with key industry groups to ensure that the results, conclusions, needs for further technology development, and identified issues are effectively communicated.

Appendix 2 Summary of DER Technologies

The summary below provides a brief description of leading DER technologies. For context, it includes generic cost and performance information. Readers should note that for any given situation it is important to consult with vendors or their agents or dealers regarding actual price.

Internal Combustion/Reciprocating Engine Generators

An internal combustion reciprocating (piston-driven) engine generator set (genset) includes an internal combustion engine as prime mover coupled with an electric generator and often control and power conditioning subsystems. Sound attenuation enclosures may also be needed.

Most engines are one of two types:

- 1) compression ignition of fuel — the diesel cycle in which fuel combustion occurs as fuel is compressed causing heat leading to ignition.
- 2) “spark-ignited” combustion of fuel — the Otto cycle characterized by spark ignition of fuel (gasoline fueled automobile engines employ the Otto cycle).

These are described in more detail below.

Diesel Engine Generators

Diesel engine generator sets (gensets) consists of a diesel cycle reciprocating engine prime mover, burning diesel fuel, which is coupled to an electric generator. The diesel engine operates at a relatively high compression ratio and at relatively low rpm (compared to Otto cycle/spark engines and to combustion turbines described below).

Diesel engine gensets are very common, especially in areas where grid power is not available or is unreliable. They are manufactured in a wide range of sizes up to about 15 MW; however, for typical distributed energy applications, multiple small units, rather than one large unit, are installed for added reliability.

These power plants can be cycled frequently and operate as peak load power plants or as load-following plants. In some cases, usually at sites not connected to a power grid, diesel gensets are used for baseload operation (sometimes referred to as "village" power). Diesel gensets are proven, cost-effective, and extremely reliable, and should have a service life of 20 to 25 years if properly maintained.

Installed cost for diesel engines varies significantly. Used/refurbished models can cost as little as \$200/kW and newer, more robust, more efficient machines may cost \$500/kW or more. Depending on duty cycle and engine design, non-fuel O&M for diesel gensets operating on diesel fuel can vary widely, typically ranging from 2.5¢/kWh - 4¢/kWh, with an allowance for overhauls. Frequent cycling increases O&M costs considerably. Though fuel conversion efficiency for diesels engines can exceed 43% (fuel input of

about 7,900 Btu/kWh), typical heat rates range widely from 8,000 Btu/kWh to 10,000 Btu/kWh.

“Dual Fuel” Diesel Engine Generators

A dual-fuel engine is a diesel engine modified to use *mostly* natural gas. Diesel engines cannot operate on natural gas alone because natural gas will not combust under pressure like diesel fuel does, so they must operate in what is called “dual fuel” mode. For that, natural gas is mixed with a small portion of diesel fuel so that the resulting fuel mixture (i.e., 5 – 10% diesel fuel) *does* combust under pressure. This requires de-rating of and modest modifications to a diesel engine (i.e., for the same displacement a diesel engine modified to operate on natural gas generates less power than the same sized engine operating on diesel fuel only).

Although diesel engines are common, dual fuel versions are not. But because the underlying technology is commercial and well known, in theory natural gas fired versions (for power generation) could become much more common in sizes ranging from kilowatts to megawatts. For distributed energy systems, small multiple unit systems would probably be installed rather than one single large unit, to improve electric service reliability.

Dual fuel gensets can be cycled frequently to provide peaking power or “load following” or they can be used for baseload or cogeneration applications. They employ mostly well-proven technology and are very reliable. Service life should be at least 20 to 25 years if properly maintained.

Non-fuel O&M cost is similar to that for diesel gensets. It typically ranges from 2 - 4 ¢/kWh including allowance for overhauls. Typical heat rates also have a wide range, from 8,200 Btu/kWh to 10,000 Btu/kWh.

Spark Ignited/Otto Cycle Engine Generators

Spark-ignited combustion (Otto cycle) reciprocating engines are very common. They range in power output from a fraction of a horsepower to several megawatts. Perhaps the most familiar use for these engines is for automobiles. For stationary power applications including DER a system includes the engine as prime mover coupled with an electric generator. The engine prime mover is usually one of two types: liquid-fueled or natural gas fueled.

Although spark-ignition engines designed to use gasoline are common, natural gas fueled versions are not so common. However, because the underlying technology is commercial and well known, in theory, natural gas fired versions (for power generation) could become much more common for a variety of applications and load sizes.

Natural gas-fueled reciprocating engine gensets can be cycled frequently to provide peaking power or “load following” or they can be used for baseload or cogeneration

applications. They employ mostly well-proven technology and are very reliable. Service life should be at least 20 to 25 years if properly maintained.

Installed cost tends to range between \$400/kW – \$600/kW. O&M cost is similar to and possibly somewhat lower than that for diesel gensets. It typically ranges from 2¢/kWh – 4.5¢/kWh. Typical heat rates also have a wide range, from 8,800 to 10,500 Btu/kWh.

Combustion Turbines

Combustion turbines (also called gas turbines) burn gaseous or liquid fuel to produce electricity in a relatively efficient, reliable, cost-effective, and in some instances clean manner. Generically, combustion turbines are "expansion turbines" which derive their motive power from the expansion of hot gases through a turbine with multiple blades. The resulting high-speed rotary motion is converted to electricity via a generator. A full generation system consists of the turbine itself, a compressor, a combustor, power conditioning equipment (usually electricity generator and transformer), a fuel handling subsystem, and possibly other subsystems, such as emissions controls or a sound attenuation enclosure.

Combustion turbine generation systems are commonplace as electricity generators and are available in sizes from hundreds of kilowatts to very large units rated at hundreds of megawatts. Combustion turbine systems have a moderate capital cost, but they often are used to burn relatively high-cost distillate oil or natural gas. Combustion turbine generation systems should have a minimum service life of 25 - 30 years if properly maintained and depending on how they are used and how often they are started up.

Depending on the size, type, and application, heat rates for commercial equipment can range from 8,000 Btu/kWh to 14,000 Btu/kWh. Non-fuel O&M costs are relatively low, typically ranging from ½ ¢/kWh - 5 ¢/kWh. Variation is a function of criteria such as turbine size, age, materials and turbine complexity, the required level of reliability, the availability of components, and maintenance requirements.

Combustion turbines can start and stop quickly and can respond to load changes rapidly, making them ideal for peaking and load-following applications. In many industrial cogeneration applications they would also make excellent sources of baseload power, especially at sizes in the 5 to 50 MW range.

"Conventional" Combustion Turbine Generators

Conventional combustion turbine generators vary significantly in price and size, and are designed for a wide range of duty cycles. Typical sizes range from 1 to 300 MW. Smaller turbines used for stationary power generation are often those developed for transportation applications, especially for marine vessels and airplanes. (Note that for those applications reliability and in some cases fuel efficiency are important performance criteria.)

Installed costs range from as low as \$300/kW for refurbished units and lighter duty machines to \$700 - \$800/kW for heavier-duty or more efficient versions, with non-fuel O&M ranging from .75¢/kWh - 4¢/kWh depending in large part on the intended duty cycle and on maintenance practices.

Microturbine Generators

Microturbines are small versions of traditional gas turbines, with very similar operational characteristics. They are based on designs developed primarily for transportation-related applications such as turbochargers and power generation in aircraft. In general, electric generators using microturbines as the prime mover are designed to be very reliable with simple designs, some with only one moving part. Typical sizes are 20 to 300 kW.

Microturbines are "near-commercial" with many demonstration and evaluation units in the field. Several companies, some of which are very large, are committed to making these devices a viable, competitive generation option. One key characteristic of microturbines is that their simple design lends itself to mass production. For the most part, prices are still being established; possibly the key Driver will be manufacturing scale. Installed price is currently in the range of about \$1,000/kW – 1,500/kW.

Definitive data on reliability, durability, and non-fuel O&M costs are just being developed; however because of simplicity and in some cases well-proven designs non-fuel O&M should be similar to that of conventional combustion turbines.

Fuel efficiency tends to be somewhat or even significantly lower than that of larger combustion turbines and internal combustion reciprocating engines, ranging from 10,000 Btu/kWh – 15,000 Btu/kWh. Note, however, that if microturbines are used in situations involving use of steam and/or hot water, then they can generate electricity and thermal energy (combined heat and power, CHP) cost-effectively.

Advanced Turbine System (ATS) Generators

The Advanced Turbine System (ATS) is being developed as a 4.2 MW, efficient, clean, low-cost power generation prime mover by Solar Turbines in conjunction with the U.S. Department of Energy. It employs the latest combustion turbine design philosophy and state-of-the-art materials. Fuel requirements are about 8,800 – 9,000 Btu/kWh. Installed cost is expected to be about \$400/kW, with non-fuel O&M expected to be below ½¢ per kWh generated.

Fuel Cells

Fuel cells are energy conversion devices that convert hydrogen (H₂) or high-quality (hydrogen-rich) fuels like methane or natural gas into electric current without combustion and with minimal environmental impacts. Because of how fuel cells convert fuel to electricity (i.e., without combustion) conversion is relatively efficient and fuel cells'

emissions of key air pollutants are much lower than for combustion technologies, especially nitrogen oxides (NO_x). Fuel cells are very modular (from a few watts to one MW).

Fuel cells are often categorized by the type of electrolyte used. The most common electrolyte for fuel cells used for stationary power is phosphoric acid; others include solid oxide and molten carbonate. Another promising type of fuel cell utilizes a proton exchange membrane, hence the name PEM fuel cell.

A fuel cell system consists of a fuel processor, the chemical conversion section (the fuel cell "stack"), and a power conditioning unit (PCU) to convert the direct current (DC) electricity from the fuel cell's stack into alternating current (AC) power for the grid, for loads, or for supporting systems such as gas purification systems.

Unless hydrogen is used as the fuel, prior to entering the fuel cell stack the raw fuel (e.g., natural gas) must be dissociated to produce hydrogen, and a supply of oxygen from air must be available. Within the fuel cell stack, the hydrogen and oxygen react to produce a voltage across the electrodes with water as a byproduct, essentially the inverse of the process that occurs in a water electrolyzer.

There are hundreds of fuel cells in service worldwide and the number of units in service is growing rapidly. Advocates are awaiting expected manufacturing advances that will reduce fuel cells' equipment cost and improve its efficiency such that they produce very low cost energy. Typical plant sizes (which can be aggregated into any plant output rating needed) are expected to range widely from a few kW to 200 kW.

Currently available fuel cells based on phosphoric-acid electrolytes have heat rates of 9,500 Btu/kWh – 10,000 Btu/kWh and cost about \$3000/kW installed. Non-fuel O&M for installed devices is about 2.5¢/kWh – 3¢/kWh.

Advanced fuel cells systems are expected to have efficiencies ranging from 40% to perhaps as high as 55% (6,300 Btu/kWh - 8,500 Btu/kWh) over the next 5 years and ultimately to cost less than \$1000/kW installed.

Energy Storage Systems

Energy storage systems used for DER applications can store energy electrochemically or as mechanical energy, and discharge electricity for use when needed. Battery energy storage systems consist of the battery and a power conditioning unit (PCU) sub-system to convert grid power from alternating current (AC) power to direct current (DC) power during battery charging, and to convert battery power from DC to AC power during battery discharge.

Most batteries can change their rate of discharge/storage in milliseconds.

There are two key elements to energy storage plant cost (unlike generators with just one):

1) *output* rated in Watts (or Volt-amps) indicating the *rate* at which the system can discharge (i.e., provide energy to a load) and 2) the *energy storage capacity*, the amount of energy that can be stored (rated in kiloWatt-hours, or kWh).

Storage is used for a variety of applications, such as:

- to increase reliability—for longer duration power outages
- to reduce impacts from an electric supply's poor power quality—for shorter duration electric service disruptions
- to take advantage of “buy low-sell high” (energy cost reduction) opportunities or of peak shaving (electric demand reduction) opportunities
- to reduce peak demand on local electricity infrastructure

Electrochemical batteries are by far the most common type of battery; primarily these are the lead-acid type, though other types are emerging as competitive options. They are proven, reliable, and highly modular. A robust international industry exists to support use of electrochemical batteries. Off-the-shelf and, in the future, “advanced” battery systems will be viable for distributed energy systems.

Plant costs range from about \$200 - \$300 per kW of maximum power output/discharge, and about \$200/kWh - \$400/kWh installed cost for each kWh of energy storage “reservoir” capacity. O&M includes replacement of battery cells and periodic watering of the cells and periodic maintenance of the PCU. Non-fuel O&M ranges from .75¢/kWh – 1.5 ¢/kWh. “Round-trip” energy efficiency (AC to DC to AC, or charge-discharge) usually ranges from 65% - 75%.

There may be limited hazardous emissions from battery charging and some batteries contain hazardous material(s).

Superconducting magnetic energy storage (SMES), flywheels, and “supercapacitors” are emerging

alternatives to electrochemical batteries, and tend to be more efficient. SMES units may be superior for larger scale applications. SMES units are being used commercially in the U.S. to stabilize voltage on transmission lines. Flywheels and supercapacitors are more modular and tend to be relatively light.

In addition to being a discrete system type, often energy storage is a key subsystem within systems employing other types of DER. Depending on the type of system, energy storage does one or more of the following: a) provide power for loads during engine start-up, b) provide electric energy needed to start the engine itself, or c) store electric energy from the DER system (or even the utility grid) for later use.

Uninterruptible Power Systems (UPS)

UPSs are connected to specific equipment, buildings or entire facilities with critical loads

to provide protection from power fluctuations lasting from just a few milliseconds to a few minutes. Specifically they provide filtered/high quality power on a continuous basis, and/or energy for use during power outages lasting several minutes. Often they have sufficient energy to power loads long enough to allow orderly shutdowns (e.g., of information or process equipment).

UPSs can be either stand-by or in-line. Stand-by devices monitor the line (power source) and provide energy as needed when problems are detected. In-line systems are connected between the power source and the load and thus can provide very complete, continuous filtering of grid power, although “throughput” losses can be as high as 40%.

Photovoltaics (PV)

Photovoltaics are semiconductor devices that convert sunlight directly to DC electricity; power conditioners (inverters) are used to convert the DC to standard AC power. Photovoltaic cells are thin layers of semiconductor (usually crystalline silicon). The cells are integrated in series and parallel into a module which is easily mountable on a structure. Modules can be attached to fixed surfaces, accepting output variations due to the sun’s position, or they can be made to track the sun for maximum output.

Photovoltaic systems using crystalline silicon are readily available. However, PV lifecycle and equipment costs are not competitive with more conventional generation technology for large-scale generation applications. Conversely, PV *is* cost-effective in a growing number of circumstances for applications requiring low power and/or small amounts of energy. Therefore remote installations and niche applications (e.g., power for communications systems, roadside emergency cellular phones, and off-grid homes) are the most common applications for PV.

Photovoltaic energy production can vary dramatically from one day to the next, due mostly to weather; and from one region to the next, due mostly to differences in latitude and climate. Frequently, battery storage and/or diesel genset systems are integrated with photovoltaics to carry loads through times when sunlight does not provide enough energy.

PV systems can cost between \$5,000 - \$10,000/kW installed, with variation driven mostly by system maximum output and cost for subsystems such as inverters, integrated engine-generator, or battery energy storage.

Wind

A wind generation system (also called a wind turbine) converts the kinetic energy in wind into mechanical work and then to electric energy. Key subsystems include: airfoil shaped blades; a rotor (to which blades are attached) that converts wind energy to rotational shaft energy; a drive train, usually including a gearbox; a tower that supports the rotor and

drive train; a generator that converts mechanical energy to electricity; and power conditioning that converts the electricity generated into a form (voltage and current frequency) used by the grid. Systems also include other equipment such as electrical wires, ground support equipment, interconnection gear, and controls.

During generation, wind passes over both surfaces of the airfoil shaped blade; air passes over the longer (upper) side of the airfoil more rapidly than it moves past the underside, creating a lower-pressure area above the airfoil. The pressure differential between top and bottom surfaces results in a force called aerodynamic lift (the same phenomenon that causes aircraft wings to “lift” an airplane).

Wind turbine electric power output varies with wind speed. The "rated wind speed" is the wind speed at which the "rated power" is achieved and generally corresponds to the point at which the conversion efficiency is near its maximum. In many systems, power output during times when wind speed exceeds the rated wind speed, turbine speed is maintained at a constant maximum level, allowing more stable system control. Note that at lower wind speeds the power output drops off sharply, as turbine output is a function of the cube of the wind speed (i.e., power available in the wind increases eight times for every doubling of wind speed).

Individual wind generation systems range in electrical output from a few Watts to over 1 MW and can be used for applications including small/residential electricity production to utility scale power generation. In both cases power from the turbine must be converted to the form used by the grid before being transferred to the grid (i.e., the process called power conditioning).

For large-scale applications, turbines are often constructed in “wind farms” whose total output can range from tens to hundreds of MW.

Controls

Control subsystems perform a variety of tasks within a DER system including:

- engine start up and shut down.
- fuel management.
- energy storage charge/discharge control.
- communications between DER subsystems and with external systems.
- monitoring and recording key performance and operational parameters.
- system diagnostics.

Power Conditioning

Unless a DER system provides power in the form needed by the grid or by loads, some type of power conditioning is required. For example, fuel cells, photovoltaics and battery systems produce direct current electricity. Power conditioning equipment called inverters

are used to convert DC electricity to alternating current (AC) electricity used by most types of electricity-using equipment.

Reciprocating engines and combustion turbines create rotational mechanical power that must be converted to electricity. To do that the engine is attached to a generator. Generators create electricity via electromagnetism using coils of wire and magnets (electricity is created by the motion of the wire coils or magnets relative to each other). Generators used with combustion turbine and reciprocating engine based DER systems usually produce electricity at frequencies and voltages that may have to be modified before being used by loads or by the grid. Step-up or step-down transformers are used to increase/decrease voltage respectively.

Data Caveats

Cost and performance information presented herein is based on data from various sources. In many cases manufacturers supplied their best current data or they developed estimations based on projected costs or fuel efficiency. Installed costs for actual distributed generation projects are usually quite site-specific.

Distributed Power Equipment and Services Vendors	
Batteries and UPSs	
American Superconductor	http://www.amsuper.com
General Electric (GE) Industrial Systems	http://www.geindustrial.com/
GNB	http://www.gnb.com/
Powercell	http://www.powercell.com/
Fuel Cells	
Avista Labs	http://www.avistalabs.com
Ballard Power Systems	http://www.ballard.com
DCH Technology	http://www.dch-technology.com
Dais Analytic	http://www.daisanalytic.com
FuelCell Energy	http://www.fce.com
GE MicroGeneration	http://www.gemicrogen.com
H Power Corp.	http://www.hpower.com
IdaTech (Northwest Power Systems)	http://www.idatech.com
International Fuel Cells (United Technologies)	http://www.internationalfuelcells.com
Matsushita Electric Industry	http://www.mei.co.jp
NuPower (Energy Partners, Inc.)	http://www.energypartners.org
Plug Power	http://www.plugpower.com
Proton Energy Systems	http://www.protonenergy.com
Sanyo	http://www.sanyo.co.jp
Siemens Westinghouse	http://www.spcf.siemens.com
Sure Power	http://www.hi-availability.com
Microturbines	
AeroVironment	http://www.aerovironment.com/
Capstone	http://www.capstoneturbine.com
Elliott Energy Systems/MagneTek	http://www.magnatek.com/
GE Power Systems	http://www.ge.com
Honeywell Parallon Power Systems	http://www.parallon75.com/
Ingersoll-Rand Energy Systems	http://www.ingersoll-rand.com/energystystems
Solo Energy Corp.	
Turbec AB	
PowerPac (Elliot Microturbine Systems)	http://www.powerpac.com/turbine.html
Williams Distributed Power Services	http://www.williams-gen.com
Photovoltaics	
Amonix	http://www.amonix.com/
Applied Power	http://www.appliedpower.com/
ASE Americas	http://www.asepv.com
AstroPower	http://www.astropower.com

BP Solarex	http://www.solarex.com
Ebara Solar	http://www.ebara.co.jp
Energy Conversion Devices	http://www.ovonic.com/
Evergreen Solar	http://www.evergreensolar.com
Kyocera	http://www.kyocera.com
PowerLight	http://www.powerlight.com/
Photowatt International	http://www.photowatt.com
Sharp	http://www.sharp-usa.com
Shell Renewables	http://www.shell.com
Siemens Solar	http://www.siemenssolar.com
Solar Electric Light Company	http://www.selco-intl.com
Solarex	http://www.solarex.com/
Internal Combustion Engines	
Caterpillar	http://www.cat.com
Cooper Energy Services	http://www.cooperenergy.com
Cummins Energy Company	http://www.cummins.com
Detroit Diesel	http://www.detroitdiesel.com
Electryon	http://www.electryon.com
Honda	http://www.honda.com
Jenbacher Energie-systeme AG	http://www.jenbacher.com
Kohler Generators	http://www.kohlergenerators.com
MAN B&W Diesel	http://www.manbw.dk
SenerTec	http://www.senertec.de
Wartsila Diesel	http://www.wartsila-nsd.com
Waukesha Engine	http://www.waukeshaengine.com
Stirling Engines	
BG Technology	http://www.bgtech.co.uk
SIG Swiss Industrial Company	http://www.sig-group.com
Sigma Elektroteknisk A.S.	http://www.sigma-el.com
Solo Kleinmotoren GmbH	http://www.solo-germany.com
Stirling Technology Company	http://www.stirlingtech.com
Stirling Technology, Inc.	http://www.stirling-tech.com

Sunpower, Inc.	http://www.sunpower.com
Tamin Enterprises	http://www.tamin.com
Whisper Tech Ltd.	http://www.whispertech.co.nz
Wind Turbines	
Bergey WindPower	http://www.bergey.com
Bonus Energy A/S	http://www.bonus.dk
Dewind Technik	http://www.dewind.de
Ecotecnia	http://www.icaen.es/icaendee/ent/ecotech.htm
Enercon	http://www.enercon.de
Enron Wind	http://www.wind.eneron.com
Gamesa Eolica	http://www.gamesa.es
Mitsubishi Heavy Industries	http://www.mhi.co.jp
NEG Micon	http://www.neg-micon.dk
Nordex	http://www.nordex.dk
Nordic Windpower	http://www.nwp.se
Vesta Wind Systems A/S	http://www.vestas.com
Controls	
ASCO Controls	http://www.asco.com/
Encorp	http://www.encorp.com/
GE Zenith Controls	http://www.zenithcontrols.com/
Woodward Industrial Controls	http://www.woodward.com/
Schweitzer	http://www.sch
Combined Heat and Power	
Asea Brown Boveri	http://www.abl
Inverters and Power Conditioning Systems	
Advanced Energy Systems	http://www.advancedenergy.com/
AeroVironment	http://www.aerovironment.com/
Heart Interface	http://www.heartinterface.com/
Omnion Power Engineering	http://www.omnion.com/
Trace Engineering	http://www.traceengineering.com/
Trace Technologies	http://www.tracetechnologies.com/
MajorPower	http://www.majorpower.com/
California Energy Commission Inverter Buy-down Program	http://www.energy.ca.gov/greengrid/certified_inverters.html
Organizations	
Distributed Power Coalition of America	http://www.dpc.org/

Appendix 3 Transmission and Distribution Cost/Benefits

Deferral of Capital Expenditures

As load on a distribution system grows, eventually a point is reached when the load outgrows the capacity of one or more components of the power system, such as a transformer or distribution line (feeder). The traditional utility response to this situation is to install additional capital equipment to relieve the overloading. Not investing in capacity upgrades increases the risk that system components will fail under stress, degrading reliability and increasing O&M costs.

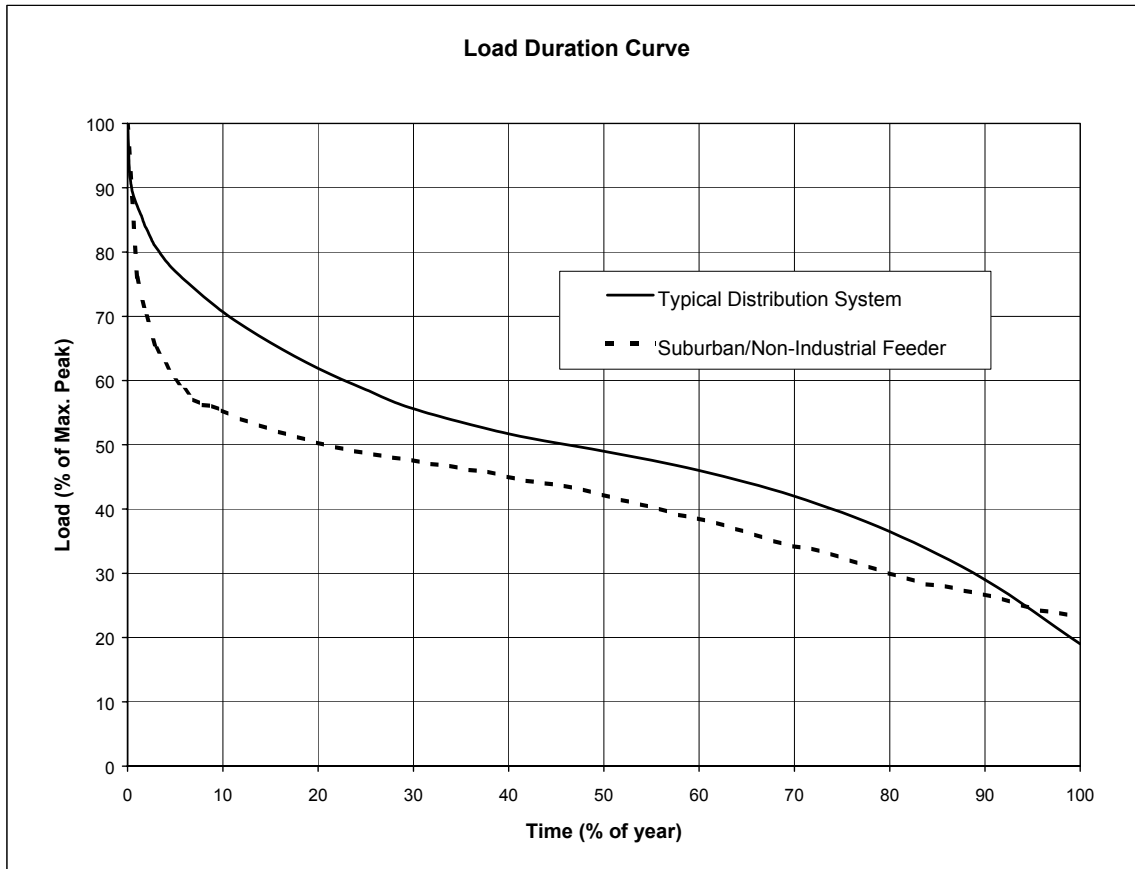
A load duration curve is an analysis tool used to depict the amount of time (in percent) during a year that the load on a system is above a given fraction of its maximum (peak) value. Typical load duration curves for distribution systems are shown in Figure 4-4. Since load duration curves are normalized to the peak during the year, the curve begins at 100% decline steadily to the right, eventually showing the minimum load point on the right hand edge. At any point in between, a load duration curve shows the need to serve load relative to the peak demand. For example, for a typical T&D distribution system with a mix of residential, commercial and industrial load (the solid curve in Figure 4-4), the total load will exceed 70% of its peak for only about 10% of the year, or about 900 hours.

The load will exceed 80% of peak for only about 3% of the year, about 260 hours. While extreme peaks are very infrequent events, the T&D system is designed specifically to serve peak loads, and thus growth in peak loading determines when action is needed to prevent system overloads during peaks.

The dashed curve in Figure 4-4 depicts the load duration characteristics of a feeder that is primarily residential and commercial with a minimal industrial component, a characteristic that is increasingly common for many feeder systems in suburban areas. The load profile of this feeder is characterized by a higher component of air conditioning load during summer peaks. For this curve, the 70% load level corresponds to about 2% of the year (175 hours), and the 80% load level to less than 1% of the year (about 80 hours).

Understanding the duration of loads on a feeder indicates how much distributed generation could be used for reducing peak demands on the distribution wires, and how many hours of operation on peak would be needed.

Figure 4-4: Load Duration Curves



These curves clearly illustrate the potential for DER as a peaking resource to defer or avoid T&D capital investments. As the load grows past the capacity of the distribution system to handle the peaks, small amounts of DER operating few hours per year could “clip” the top of the curve by meeting applicants’ energy needs at the point of use rather than relying on grid-delivered power. For either of the curves in Figure 4-4, and assuming that the peak feeder load is 10 MW, it would appear that 1 MW of distributed generation operating less than 100 hours per year would provide relief for feeder line loads during times when the feeder is under its most severe situations.

Capacity costs are quantified in terms of dollars per kilowatt per year (\$/kW-yr). budgets for capacity upgrades can be translated into capacity costs by dividing the budget dollars by the capacity in kW that those upgrades provide:

$$\text{Capacity cost, } \$/\text{kW-yr} = \frac{\text{Budget\$}}{(\text{kW}) * (\text{years})}$$

The benefit is calculated by evaluating the present worth of the kW deferred. A present worth calculation assumes a certain number of megawatts installed each year, with costs

discounted according to the estimated interest rate and referred back to the present year.

Benefit, \$/year = Present Worth {(kW of DER)*(capacity cost, \$/kW-yr)*(# of years)}

Example Calculation

Consider the case in which transmission capacity planned for the next ten years is 1000 MW, at a budget of \$200 million. Assume the capacity would be installed in equal increments of 100 MW each year.

Installing 100 MW of DER this year can defer 100 MW of capacity for one year:

$$\begin{aligned}\text{Capacity cost, \$ /kW-yr} &= (\$200,000,000)/((1,000,000 \text{ kW})*(10 \text{ years})) \\ &= 20 \text{ \$ /kW-yr}\end{aligned}$$

$$\begin{aligned}\text{Benefit (\$)} &= (100,000 \text{ kW})*(20 \text{ \$ /kW-yr})*(1 \text{ year}) \\ &= \$2,000,000\end{aligned}$$

Utilization Of Existing Transmission and Distribution Assets

If DER is used to serve peak load growth, the load duration curve will “flatten” out; the existing distribution system will become loaded to a higher percentage of its maximum capability more of the time, and become more fully utilized. In general, the closer to the load distributed generation can be located, the greater the asset utilization benefits are possible. DER located on the distribution system, whether by the utility, a third party working with the utility, or a customer placing DER on his premises, can reduce the need for both transmission and distribution upgrades and will likewise increase the utilization of these assets. A utility can use this knowledge to conduct a strategic review of its T&D system and identify key feeders and substations with fast-growing load or poor utilization that would benefit from DER deployment.

Distribution System Reliability

Distributed generation can have a positive impact on system and local distribution reliability. For a Transmission and Distribution Utility (T&D) the primary economic impact of poor reliability is increased expenditures for emergency maintenance. An analysis of applicant loads and local reliability data would allow a T&D to identify locations where DER could have the best impact on reliability improvement. Where T&Ds cannot own or operate DER, they can work strategically with energy service companies, vendors and customers to contract for DER in places where reliability

enhancement is desired.

Qualitative distributed generation reliability benefits include faster restoration times, and improved feeder reliability due to reduced stress and overloading of feeder equipment. Other hard-to quantify benefits include customer good will, customer retention, and avoided damage claims and/or lawsuits.

Risk Transfer

Regulators have assigned to the T&Ds the full responsibility for the safe and effective delivery of power to all customers on its distribution system. It has the responsibility to design and operate the distribution system to meet voltage and frequency limits and power quality metrics set by the standard practices in the T&D. The advent of customer-owned and -operated DER in the system adds complexity and uncertainty to the operation of the distribution system, and shifts some of the responsibility for power delivery from the utility to the DER-using customer.

Where a customer has installed DER, the T&D has four options regarding future nearby wire upgrades:

- 1) Ignore the presence of the DER unit and invest in wires as if the DER did not exist (implicitly discounting the unit's peak load reduction impacts).
- 2) Include the likelihood that the unit will be on during feeder peak times (implicitly anticipating that the unit will reduce feeder peak loads).
- 3) Establish formal agreements and incentives by contract with the DER owner to encourage DER operations at peak and reduce the T&D's responsibility for delivery at peak to that customer.
- 4) Account for the existence of any customer-owned DER on the distribution system by planning to handle the composite, statistical net (of DER) customer loads on feeders and substations.

Using approach 1), the T&D will continue to plan and finance "lumps" of distribution capacity to accommodate the expected load growth over a specified planning horizon. Not only is most of the new capacity not used in the early years of the upgrade, but if the load does not grow as forecasted, the investment decision becomes (retrospectively) a poor one. Not accounting for customer DER can lead to over-investment in unneeded capacity.

Using approach 2), the utility will defer its own capital investment due to the capital investment of the customer in the distributed generation unit. In essence the T&D has chosen to "lean" on the customer's DER. Note that the logic would be the same in the case of the T&D requesting load reductions by some of the customers on the feeder and trusting that the load reductions will be available during the distribution system peak.

But the utility is also assuming that the DER will operate during critical peak times as designed, for example with high availability and good power quality. If either of these operational assumptions is false, especially during severe peak feeder load periods the utility will have to shed customer load, risk physical damage to the wires, or risk experiencing electrical parameters outside of normal specifications. In this sense the utility has increased its risk in exchange for the right to lean on the customer DER.

Assuming that the customer owning the DER has not been compensated for the “leaning rights,” the customer is under no obligation to the T&D for failing to operate the DER in the way anticipated by the T&D. Using approach 3), in which the utility and the customer have signed a performance contract, the customer’s compensation should be impacted by his failure to supply those services. A utility that designs and builds to accommodate installed DER should also have contractual assurance that the customer’s load is shed first if the DER is tripped off-line.

The magnitude of the savings from relying on customer-owned and -operated DER to defer T&D investments can be substantial, essentially equivalent to a permanent deferral of all anticipated reinforcements, including land acquisition, new substation equipment, etc.

Approach 4) uses the measured loads on feeders for planning purposes, unadjusted for known DER on the distribution feeder. Only a modest amount of risk is placed on the T&D in this case. The DERs on the feeder are seen essentially as load reduction and are smoothed out statistically. If multiple DERs are in place, their unreliability is probably smoothed out also.

An important case of very large benefit to the T&D is relying on the customer DER to hedge the risk of planning for uncertain “block” loads. These are loads that represent a significant quantum increase in feeder load in a single year, such as a commercial or industrial facility coming on-line. If the load is delayed or fails to materialize as planned, any investments the utility may have made in wires upgrades to accommodate the load will become negative financial impacts. Using DER to hedge such load growth uncertainty can be very valuable.

T&D Costs of Accommodating DER

The T&D’s accommodation of customer DER will have some adverse impacts on the T&D:

- The T&D pays for needed hardware upgrades (e.g., DER-compatible breakers, reverse power relays, sensors, instrumentation, communication devices and/or meters) to the distribution system to accommodate DER (to the extent that the costs for such upgrades are allocated to the T&D and not the customers).
- To the extent that the T&D relies on the DER to support the grid, the T&D assumes additional risk, since the DER may not be as reliable as the wires investments it displaced or deferred.

- The T&D must pay for some engineering staff time and study costs.
- The T&D must provide training to its staff to anticipate and understand the implications of customer-owned and -operated DER.

However, most of these costs are no different than the costs of planning, owning and operating a T&D system with full risk and responsibility for high-reliability electric distribution service.

Customer Benefits and Costs

Bill Reduction: Avoided Energy Costs and Demand Charges

A customer's bill consists of two categories of charges — energy and demand.

Energy is the commodity purchased from the utility or retail electric provider (REP), and is measured in kilowatt-hours (kWh). The price per kWh charged may be higher the more energy is used; e.g., one price can be charged for up to (say) 1,000 kWh, and a higher price for every kWh above that threshold. Energy can also be more expensive during certain times, such as system peaks; this is called time-of-use (TOU) pricing.

Peaking energy prices can be high at certain times in today's market. When system peaks occur, if supplies are tight, spot energy prices can skyrocket, although they may be subject to caps by regulation or ISO rules. DER can represent insurance against risk of high energy prices and a means of energy price management.

Demand charges (for commercial and industrial customers) are fixed monthly charges based on the highest instantaneous load the customer may have during the month, although the specific terms may vary under different customer contracts or tariffs. For example, if the customer's peak load is 10 kW, even if it's only for one hour, he is charged a monthly fee based on that 10 kW. Thus, by producing power at peak times, a DER can help a customer reduce both energy and demand charges. Peak periods may total a relatively few hours per month, but may represent a significant percentage of a customer's total bill.

In order to justify using a DER in baseload operation, a careful analysis of the customer's processes and economics is needed. Low-cost fuel must be available, allowing the customer to produce power for a lower cost than the REP would charge. DERs suitable for baseload use tend to be more efficient and require generally lower O&M than peaking units. Using combined heat and power (CHP, also known as cogeneration, in which the customer produces electric energy from a DER but also utilizes waste heat from the generator for industrial processes, space or water heating, or other uses) typically increases overall economic efficiency substantially, increasing the probability that baseload DER operation will be economic for the customer.

Calculation of the estimated cost savings from a DER is relatively straightforward. A review of the energy consumption and demand charges recorded on the customer's recent billing statements will reveal how much energy is used during which time periods, and what the costs are. DER size is matched to the peak load reduction desired, or the full customer load if baseload operation is desired, and hours of operation are determined. Total monthly costs are computed, consisting of all fixed and variable costs of running the DER in the desired mode plus energy and demand charges for whatever portion of customer requirements are not met by the DER. The cost of the DER itself must also be included, using suitable financial parameters. The difference between the no-DER situation and the with-DER case is the projected cost savings of using the DER.

The cost of energy, whether purchased from the utility or generated on-site, is the product of power (in kW) times the number of hours of operation times the cost per kilowatt-hour:

$$\text{Energy cost} = (\text{kW}) * (\text{hours}) * (\$/\text{kWh})$$

Both power level and energy cost are variable with time. Typically, energy costs are computed on an hourly basis, summing the results to a monthly total. Energy cost savings due to DER use would be computed by first calculating total energy costs the customer would have paid absent the DER, and subtracting the total energy costs paid with the DER.

The demand charge from the utility is the product of the customer's peak power demand during the month (in kW) times the monthly charge per kW of peak demand:

$$\text{Demand charge, per month} = (\text{peak kW}) * (\$/\text{kW/month})$$

The demand charge savings due to using a DER for peak reduction is the product of the customer's peak power demand reduction (equal to the size of the DER) times the charge per kilowatt-hour:

$$\text{Demand charge savings, per month} = (\text{kW of DER}) * (\$/\text{kW/month})$$

Example Calculation

Demand charge savings, per month = (kW of DER)*(\$/kW/month)

Consider the case where:

- The utility charges 3¢/kWh off-peak, and 12¢/kWh on-peak.
- Utility demand charges are \$10/kW/month.
- The customer's load is 2000 kW during peak periods, for 6 hours/day, 20 days per month; all other times the load is 1000 kW.
- The customer owns a 1000 kW gas turbine that operates at a cost of 6¢/kWh, inclusive of fuel and all O&M.

The customer operates the gas turbine to cut load during peak periods; the customer generates 1000 kW and buys 1000 kW from the utility. (Off-peak utility usage won't change, since it's cheaper to buy than generate during off-peak.) For peak periods, on a per-month basis:

$$\begin{aligned}\text{Energy cost, no DER} &= (2000 \text{ kW}) * (6 \text{ hrs/day}) * (20 \text{ days/month}) * (12 \text{ ¢/kWh}) \\ &= \$28,800/\text{month}\end{aligned}$$

$$\begin{aligned}\text{Energy cost, with DER} &= (1000 \text{ kW}) * (6 \text{ hrs/day}) * (20 \text{ days/month}) * (12 \text{ ¢/kWh}) + \\ &\quad (1000 \text{ kW}) * (6 \text{ hrs/day}) * (20 \text{ days/month}) * (6 \text{ ¢/kWh}) \\ &= (\$14,400 + \$7,200) \text{ per month} \\ &= \$21,600 \text{ per month}\end{aligned}$$

$$\begin{aligned}\text{Energy cost savings} &= \$28,800 - \$21,600 \text{ per month} \\ &= \$7,200 \text{ per month}\end{aligned}$$

$$\begin{aligned}\text{Demand charge savings} &= (1000 \text{ kW}) * (10 \text{ \$/kW/month}) \\ &= \$10,000 \text{ per month}\end{aligned}$$

The customer's total savings = \$17,200 per month

On-Site Reliability

To serve critical loads during sustained T&D outages, a customer would use a DER capable of being started up in a matter of minutes, and operated for the duration of the outage. The cost of purchasing, maintaining and operating a DER for reliability enhancement would need to be cost-justified based on the expected number and duration of T&D outages and the estimated costs of those outages to the customer.

The customer's "value of service" (VOS) will vary according to a customer's individual situation, and may be subjective to some degree. Residential customers experience inconvenience, but usually do not suffer significant economic losses for most outages, which normally last only a few minutes to a few hours. Research¹ has determined that residential VOS is valued in the vicinity of \$1/kWh.

¹ Pupp, Roger and Woo, C.-K.: Costs of Service Disruptions to Electricity Customers, The Analysis Group, Inc., January 1991.

For commercial and industrial customers, the VOS can be much greater, depending on the process that is interrupted. Product and equipment can be damaged, revenue lost, and labor forces idled until power is restored. Research has estimated the VOS for these customer classes to be in the range of \$10 to \$70 per kWh [Ibid.].

Note: Operating a DER to serve customer load when the T&D supply is interrupted requires “islanded” operation, i.e., there is no live connection between the customer and the T&D at the point of common coupling, and the DER operates only to serve local load. Interconnection rules will specify the protection equipment that must be installed to prevent the DER from reconnecting with the T&D until such time as T&D service is restored.

Assuming that the costs to a DER owner are proportional to the length of the outage, the value of service interruptions on a yearly basis can be calculated from the following equation:

$$\text{Benefit, \$ /year} = (\text{kW of load}) * ((\text{SAIDI, min/yr}) / 60) * (\text{VOS, \$ /kWh})$$

where: SAIDI for the feeder supplying the customer = system average interruption duration index (minutes/year)

Alternatively, there may be fixed costs associated with an outage, regardless of the length of the outage. In this case, the value is the fixed cost times the number of times per year the interruption occurs:

$$\text{Benefit, \$ /year} = (\text{SAIFI, outages/yr}) * (\text{FC, \$ /outage})$$

where: SAIFI for the feeder supplying the customer = system average interruption frequency index (outages/year)

The total benefit to the customer may be a combination of these two values.

Example Calculation

Consider the case where:

Customer load = 1000 kW

SAIDI = 90 min/year

SAIFI = 1.25 outages/year

VOS = \$50/kWh

FC = \$5,000

For this situation, installing a DER that is capable of providing standby service provides the DER owner an estimated yearly reliability benefit of:

$$\begin{aligned}\text{Benefit, \$/year} &= (1000 \text{ kW}) * ((90 \text{ min/yr}) / 60) * (50 \text{ \$/kWh}) \\ &\quad + (1.25 \text{ outages/yr}) * (5000 \text{ \$/outage}) \\ &= (\$75,000 + \$6,250) \text{ per year} \\ &= \$81,250 \text{ per year}\end{aligned}$$

Power Quality Improvement

Power quality is related to reliability in some ways, and the potential solutions can be similar to those for reliability. In general, power quality problems tend to be short in duration and small in magnitude, but frequent or constant in occurrence. They may include voltage sags or spikes, switching transients, harmonics (frequencies other than 60 Hz), noise, and momentary outages (less than 5 minutes, according to the definition in the IEEE Reliability Standard 1366; there is no similar standard for power quality).

Customers can experience many of the same consequences from poor power quality (PQ) as they would from poor reliability. For many industrial and commercial customers a momentary outage is just as bad as a sustained outage, since production processes or electronic equipment and records may be disrupted in either case. If so, benefits may be computed according to the same value of service principles as described in the previous section on reliability.

Resolving power quality issues can be difficult, since the problems may have their origin in the T&D system, the customer's own equipment, the equipment of other customers on the feeder, or an interaction between any combination of these parties' systems. The proliferation of solid-state electronics, in customer equipment as well as T&D equipment, is frequently the source of many PQ anomalies.

Since many PQ symptoms are low-energy or short-term phenomena, distributed storage

(e.g., batteries or flywheels) linked to the customer's most sensitive loads may be an economic solution, relative to the expense and effort of implementing a DER system. A power conditioning system (power electronics-based converter system) or an isolation transformer may be economical alternatives as well. Whatever system is used, the basic approach is to interpose the system between the customer and the T&D, so as to filter or smooth out PQ anomalies.

Other Benefits and Costs

This category of benefits and costs arising from installation and operation of DER cannot, at this time, be directly allocated to any particular stakeholder or participant in the DER market. Before electric industry restructuring occurred, these impacts would have been included in an integrated utility's analysis of total benefit and cost impacts of DER. In the current ongoing evolution of industry restructuring, it may be worthwhile to analyze these impacts and evaluate how they may be allocated in the future.

Line Losses

When transmitting electric energy through T&D transmission and distribution systems, the impedance (electrical resistance) of wires and transformers causes resistive or " I^2R " losses, where I is the current in the line in amperes (A) and R is its resistance, in ohms (Ω). These losses are typically on the order of 4 to 7% system-wide; that is, about that much of the total energy generated is lost in transit from generation sources to loads. This energy must be generated or purchased, just like any other energy the T&D requires.

DER can reduce line losses by providing more of the supply locally, rather than through transmission and distribution lines. This benefit is more likely to be quantified on radial distribution lines than on networked distribution or transmission lines. The reduction in line loading due to a distributed generator can be directly seen on a distribution feeder, whereas the impact on a network is spread over multiple lines.

If the system or T&D-specific average losses are known, then the average line loss reduction can be calculated as a simple percentage of the DER capacity. This kind of data would need to be compiled from a combination of transmission data (from the ISO), FERC filed data or other sources. If, for example, an average T&D line loss figure is 7% (this is comparable to other T&D utilities nationwide), then approximately 1.075 MW of energy input into the T&D system is required to serve 1.0 MW of actual load. Therefore, every 1 MW of DER can be considered to result in an average benefit of 75 kW of avoided line losses during the time it operates. This approach takes advantage of known system characteristics to attribute total line loss savings to a specified DER amount.

This reduction also has implications for capacity requirements. A 7.5% reduction in energy losses from DER use at the point of customer load translates into that much less generation, transmission and distribution capacity that would otherwise have to be built to generate and transport that energy.

Reserve Margin

Reserve margin is the amount of capacity cushion (denominated in MW) a power region requires to be available to serve as a safety margin at extremely high load times. This extra capacity allows the system generation controllers or operators to dispatch plants with an additional surety that the system will not collapse if an outage of a single transmission line or generating plant occurs. The reserve margin takes into account the instantaneous status of all available generation and transmission assets.

At this time, DER is not sufficiently proven or prevalent in the electric system to warrant explicit and separate inclusion in reserve margin calculations. Once there is a significant amount of DER installed and exporting into the electric grid, and concomitant experience with operating DER, future DER can be included in reserve margin calculations. For now, customer load served by on-site DER is included in calculations of reserve margin requirements, while the DER is not counted as a generation resource.

Most system peak loads occur in only a relatively few hours per year (<300 or so). Reserve margin plants do not usually have high efficiency or low emissions due to their very low capacity factor. Customer units, such as standby generators which are configured for remote dispatch on demand, might be excellent candidates for consideration as reserve margin status and benefits. However, the PUCT will include DER capacity in calculations of installed generation capacity for purposes of market share calculations.

Small increments of DER can be added as the load grows, sized to accommodate the amount of load that exceeds the capacity limit. This contrasts with typical capacity additions that are usually large, “lumpy” capital investments. DER can therefore be more cost-effective, flexible, and a less risky way to meet load growth.

If DER is connected to the transmission system it can displace the need for incremental generation capacity, and may reduce transmission line losses.

Reserve margin capacity costs are quantified in terms of dollars per kilowatt per year (\$/kW-yr), and can apply to generation and/or transmission capacity. The benefit due to DER installation is calculated by evaluating the present worth of the kW deferred. A present worth calculation assumes a certain number of megawatts installed each year, referred back to the present year.

$$\text{Benefit (\$)} = \text{Present Worth } \{(\# \text{ of kW}) * (\$/\text{kW-yr}) * (\# \text{ of years})\}$$

Example Calculation

Consider the case in which generation capacity planned for the next ten years is 1000 MW, at a budget of \$500 million. Assume the capacity would be installed in equal increments of 100 MW each year.

Installing 100 MW of DER this year can defer 100 MW of capacity for one year:

$$\begin{aligned} \text{Capacity cost, } \$/\text{kW-yr} &= (\$500,000,000) / ((1,000,000 \text{ kW}) * (10 \text{ years})) \\ &= 50 \$/\text{kW-yr} \end{aligned}$$

$$\begin{aligned} \text{Benefit (\$)} &= (100,000 \text{ kW}) * (50 \$/\text{kW-yr}) * (1 \text{ year}) \\ &= \$5,000,000 \end{aligned}$$

Ancillary Services

Ancillary services comprise a number of valuable electrical attributes that are required for the safe, reliable and efficient operation of a power system. Typically provided by large central plants for reasons of economy and simplicity of operation, several types of ancillary services can also be provided by distributed generators. In fact, given that many DER technologies are nearly as efficient as new central generation, they may actually be more efficient in delivering ancillary service, especially when locational advantages are figured into the equation (as with line losses). It is anticipated that there will be markets for ancillary services just as there are for bulk generation; the buyer(s) of the services might be the generators, QSEs or the ISO. Identification of beneficiaries and development of economic accounting tools for ancillary services are key unresolved issues of utility restructuring.

Logistically, ancillary services could be procured from DERs that are directly controlled and dispatched by a QSE or the ISO; that is, the DERs would have communication and control equipment installed so that they could be monitored and dispatched.

Alternatively, the ISO could contract with DERs to operate at certain times and with specified performance requirements, with economic penalties for non-performance.

Examples of ancillary services include:

Volt/var Control

DER can be used in lieu of capacitors or other devices to provide the reactive power (kvar) needed to improve or control voltage profiles on distribution feeders, and to

generally improve overall system voltage. Capacity values of \$/kvar should be readily available from the T&D utility for each voltage level in the system, representing the equipment cost of capacitors that the T&D utility would purchase for voltage correction. Improvement in system voltage profile contributes to increased stability margin as well, since the system is less susceptible to voltage collapse during contingencies.

Reliability Must Run (RMR)

DERs are located and operated in specific areas and for specific times to relieve transmission constraints.

Spinning Reserve

The DER operates at reduced load, but ready to pick up additional load if another generator (or generators) in a specified area are forced out of service.

Load Frequency Control

The DER acts as a “swing bus”: it adjusts its output to compensate for normal variations in customer load, in order to keep system frequency constant.

Load Following

The DER “tracks” a particular load, i.e., it adjusts its output so that the load has minimal effect on the rest of the system.

Scheduling And Unit Commitment

Large generating plants can be uneconomical to use for cycling duty or for reliability-must-run applications where the capacity needs are small or the number of hours of operation are few. Using DERs can be more economical than committing a large plant for these purposes.

Black Start Capability

After a T&D outage, a DER can bring up local loads (forming a “micro-grid”) and eventually re-synchronize with the grid, lessening the difficulty of system restoration

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